STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7032

Joint Petition of Vermont Electric Power Company, Inc. ("VELCO"), Green Mountain Power Corporation ("GMP") and the Town of Stowe Electric Department ("Stowe") for a Certificate of Public Good pursuant to 30 V.S.A. § 248 authorizing VELCO to upgrade a substation in Moretown, Vermont; construct .3 miles of side by side, single pole tap; construct a switching station in Duxbury, Vermont; construct 9.4 miles of 115 kV transmission line; upgrade an existing GMP 34.5 kV subtransmission line; construct a substation in Stowe, Vermont; and for Stowe to construct 1.05 miles of 34.5 kV subtransmission line in Stowe, Vermont.

DIRECT TESTIMONY OF
GEORGE E. SMITH
ON BEHALF OF THE
VERMONT DEPARTMENT OF PUBLIC SERVICE

April 11, 2005

Summary: The purpose of Mr. Smith's testimony is to describe his review and technical evaluation

of the proposed project from a transmission perspective and to provide conclusions and recommendations resulting from this review.

Direct Testimony
of
George E. Smith

Identification of Witness and Qualifications

Q. Please state your name, position, and qualifications.

A. My name is George E. Smith and I am a professional engineer licensed by the State of Vermont (registration No. 7486). I have degrees in electrical engineering with 23 years experience in power transmission systems in areas including system planning, system protection and management of transmission engineering, construction and maintenance. I have worked as a consulting engineer since June of 2000. I also serve as a member on the executive committee of the New York State Reliability Council. My resume is attached as Exhibit DPS-GES-1.

Q. Have you testified before the Public Service Board (Board) before?

A. Yes. I have testified on behalf of VELCO on previous occasions regarding the emergency restoration of the PV20 circuit resulting from ice damage, Docket No. 5742; the installation of the PV20 causeway cable, Docket No. 5778; and the installation of the VELCO Essex substation flexible alternating current transmission system (FACTS) device and associated substation upgrade, Docket No. 6252. I have also testified on behalf of the Department of Public Service (Department) on the Northwest Reliability Project, Docket No. 6860.

Overview

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe my review and technical evaluation of the petitioners’ proposal in this case, from a transmission perspective, and to provide conclusions and recommendations resulting from this review.

Q. What questions did you seek to answer in your review?

A. In general, I sought to answer the following:

1) Is there a need for a transmission system upgrade?

2) Does the project as proposed meet this need?

3) What are the transmission alternatives to the proposed project?

4) Is the project as proposed the best alternative among available transmission options?

5) Is an alternate route that follows the Little River advisable?

6) What alternate structure configurations are available for potential aesthetic improvements?

7) What are the estimated costs of the proposed project?

8) What are the cost and reliability implications of undergrounding?

9) What are the impacts of the project on system reliability and stability?

10) What are the operational impacts of the proposed project?

11) Would the proposed project be safe?

12) Are the noise impacts acceptable? And

13) What is the impact of the proposed project on electrical losses and efficiency?

Q. What sections of 30 V.S.A. § 248 are addressed by your testimony?

A. My testimony will address 30 V.S.A. § 248 (b)(2), the so-called least-cost criteria; 30 V.S.A. § 248 (b)(3), stability and reliability; and 30 V.S.A. § 248 (b)(4), economic benefit to the state. Regarding 30 V.S.A. § 248 (b)(2) and 30 V.S.A. § 248 (b)(4), I will testify that, generally, the petitioners' proposal provides the greatest benefits with respect to costs among the available transmission solutions, and that the Lamoille project is required to provide the area in question with reliable electric power, thereby providing benefits to the state and its residents. Sections 30 V.S.A. § 248 (b)(2) and 30 V.S.A. § 248 (b)(4) will also be addressed by Department witness Riley Allen. Department witness Sean Foley will also address criterion 30 V.S.A. § 248 (b)(4). Regarding 30 V.S.A. § 248 (b)(3), I will testify that the proposed project is required for the reliability of the area transmission system and that the project would not have an adverse effect on system stability.

Summary of Conclusions

Q. Please summarize the conclusions that you reached as a result of reviewing the proposed project.

A. A summary of my conclusions follows:

1) A transmission system upgrade is needed absent the implementation of sufficient local generation or demand side resources.

2) The basic components of the proposed project, i.e., a 115 kV line together with a 115 kV to 34.5 kV substation in Stowe, are the best alternative to meet the need.

3) Rerouting the 115 kV line along the Little River is not advised.

4) Alternative structure configurations are available, including a single pole double circuit configuration.

5) The petitioners' cost estimates for the proposed project may be overstated.

6) While undergrounding does not pose a significant reliability concern, the costs for undergrounding are significant.

7) The proposed project enhances system reliability and stability.

8) The proposed project enhances the ability to operate the system.

9) The proposed project is safe.

10) The proposed substation should be monitored for unexpected noise impacts. Adverse noise impacts should be corrected post construction. And

11) The proposed project provides significant line losses savings.

Need for the Proposed Project

Q. To begin, please describe the local area transmission system that is at issue in this proceeding.

A. The local area transmission system at issue in this proceeding, or Lamoille County

Study Area (LCSA), is a network of 34.5 kV subtransmission lines that are primarily supplied by three VELCO 115 kV to 34.5 kV step-down substations located in Middlesex, East Fairfax and Irasburg. This network is a looped network, i.e., the majority of the distribution substations supplied by the network have the benefit of service from two directions. During load levels when the transmission capacity is adequate, reliable electrical service is maintained to these substations following a contingency.[1]

Q. Do you agree with the petitioners that there is a need for a system upgrade to the subtransmission system described above?

A. Yes. Under the assumption that demand side management or distributed generation is not available in sufficient quantities to address the needs, a transmission solution would be required in this area.[2]

Q. Please describe the needs of the transmission system in this area.

A. This area has two distinct needs. First, even with all of the area's subtransmission lines in service, the so-called "all lines in" condition, when the area load reaches 74 MW[3] the present system would be incapable of supplying the loads and maintaining voltages above 95%.[4] At 81

---

[1]For an electrical system, a contingency is an event that involves the loss of a system element such as a transformer, transmission line, bus section or circuit breaker from service. The causes of a contingency include lightning strikes, equipment failures, and trees falling into lines.

[2]The availability of demand side management and distributed generation is addressed by Department witnesses Carole Welch and Riley Allen.

[3]The LCSA reached a peak load level of 73.85 MW in December 2004.

[4] A voltage level of 95% is required with "all lines in" in order to provide margin for a contingency due to the fact that voltage normally experiences a sudden drop following a contingency .

MW load levels, the present system can not maintain voltage levels above 90%.[5] The load level of 81 MW could be reached within the next few years. Second, as stated above, a looped subtransmission system with adequate capacity should be capable of supplying the connected distribution substations following a line or substation contingency. However, the present system is not capable of providing this level of reliability, even at moderate load levels.

Q. At what load levels is the system incapable of serving load following a single contingency?

A. At an area load level of approximately 40 MW, the system is not capable of serving the load and maintaining acceptable voltages, say 90% or greater, following certain contingencies. At a load level of 53 MW, the area would likely suffer a voltage collapse for these contingencies.

Q. Why do you characterize the 40 MW load level as "moderate?"

A. I characterize this load level as moderate because at present day, loads above 40 MW are attained in the LCSA for over 60% of the hours in a year, and over 70% of the hours in the winter.

Q. What is the nature of the local area transmission system limitations?

A. Upon disconnection of a given line section, the transmission system should have enough capacity to supply the substation loads from the remaining lines. The two primary measures limiting capacity relate to thermal capacity and impedance. With insufficient thermal capacity,

---

[5] A precontingency voltage level of 90% provides essentially no margin for a contingency. At this level, a contingency has a good chance of causing voltage collapse and loss of load. This is especially true for systems that make extensive use of capacitors for reactive compensation, such as the LCSA. This occurs because the reactive support provided by the capacitors diminishes by the square of the voltage. For example, at 90% of nominal system voltage, capacitors will provide only 81% of their rated reactive support. At 70% of nominal system voltage, capacitors will provide only 49% of their rated reactive support. A system in a state of voltage instability is vulnerable to voltage collapse and wide-spread blackouts following any further disturbance or changes in loading.

related to wire size and ambient conditions, an overloaded line can sag below safe clearances and in extreme cases sag into an object or the ground resulting in a fault. Permanent damage can result. With too much impedance, impedance being related to line length, geometry and nominal operating voltage, low voltages occur. In severe cases, a situation of voltage collapse or blackout of a local area can occur.

Q. Above you state that the subtransmission system should be able to serve load following a contingency, or loss, of one of the subtransmission lines. Please describe how line contingencies can occur.

A. Transmission lines are susceptible to several sources of failure including lightning strikes, trees falling on the line, insulator failures, fires, extreme winds, extreme ice loading and other mechanical failures.

Q. What is the frequency of such failures?

A. According to discovery response DPS3-3, the outage rates experienced by Green Mountain Power (GMP) and Central Vermont Public Service (CVPS) in the area under consideration is 0.12 events per mile per year. This rate applies to so-called permanent faults or those faults in which the line can not be restored automatically within a few seconds.

Q. You also state that the subtransmission system should be capable of serving load after the loss of a supply source, in this case a VELCO transmission substation. What can cause the loss of a transmission substation?

A. Consider, for example, one primary source to this system - the VELCO East Fairfax substation. This source can be effectively disconnected from the area when sections of the 34.5 kV line between the VELCO East Fairfax substation and the CVPS Johnson substation are faulted. Other contingencies that would effectively remove this substation supply source from the LCSA include failure of the substation transformer, failure of other substation equipment, a bus fault, or loss of the VELCO 115 kV line from Georgia to East Fairfax. Depending on the characteristics of the specific failure, up to several days can be required for repair.

Q. Can you explain the issue of a bus fault in more detail?

A. Yes. At these substations, the 34.5 kV buses provide the junction points between the large 115 kV to 34.5 kV transformers and the out-going 34.5 kV lines. Faults on a bus can have a severe impact because the sources of supply to an area become disconnected while the loads connected to the subtransmission lines remain intact. This scenario tends to pull down the voltages in the area and can overload the remaining lines feeding the area. Bus faults can be caused by insulator and other equipment failures and are permanent in nature. Outage times required for the repair can range up to 12 hours to a day or more depending on the failure. In addition, buses need to be taken out of service for scheduled maintenance. While such maintenance is usually scheduled for low-load periods, the network at this time is necessarily weakened and vulnerable to a much larger number of contingencies.

Q. What is the appropriate reliability criteria to be applied to this subtransmission system?

A. The appropriate reliability criteria that I recommended for this situation is to maintain reliable service to all customers supplied by the area subtransmission system for the loss of any single transmission line section or for the loss of a primary supply source to the area. This is sometimes referred to as an “N-1" reliability criteria. This is appropriate because subtransmission line faults are a relatively frequent occurrence and outage of any one of several sections of line can cause a collapse of the whole LCSA. In addition, faults on the VELCO system, including transformer, bus faults or 115 kV line faults, although less frequent, can also cause collapse of the LCSA and result in protracted outages. These outages can last for several hours or more, depending on the specific circumstances, creating hardship for a large number of customers. Also, one of the primary justifications for investments in a looped system is the ability, after a contingency, to restore service to all loads, by switching, while repairs to the faulted section are underway. At present day load levels, the LCSA does not have this capability for over 40% of the hours in the winter, and 27% of the hours in a year. Given the above, together with the relatively large load served by the LCSA, I believe that an N-1 criteria is appropriate.

Q. Some substation loads in Vermont are supplied by radial subtransmission lines. Because of the inherent lack of back-up to a radial line, the N-1 criteria can not be applied to these loads. Why is it appropriate to have an N-1 criteria for the LCSA but not for those loads supplied by radial subtransmission?

A. There are several important differences. First, in the radial configuration, the number of customers served by the radial are typically much fewer than those served by a looped system such as the LCSA. Second, the radial lines are relatively short compared with the aggregate length of all portions of the loop that can cause trouble, therefore the exposure to faults is substantially less. Should a problem occur, the time to locate the problem will be less, resulting in a shorter outage time. Third, restoration of service to a radial feed, once the problem is repaired, is very simple - close the circuit breaker and the lights come back on. For a looped network, restoration is more complex, involving switching circuits back into service in a sequence and energizing capacitor banks in a sequence, depending on the problem, the location, and the load level to be picked up (which is not precisely known) at the time of the restoration. In the case of the LCSA, the restoration process requires careful coordination among all of the utility operators involved. Simply put, for the radial configuration, fewer customers are interrupted less frequently and for shorter durations.

Q. Is the N-1 reliability criteria that you cite above as stringent as that used by VELCO and by bulk transmission systems for the Northeastern United States and Canada?

A. No. Since major failures of the bulk transmission system can impact very large numbers of customers and have the potential to result in a wide area blackout, more stringent criteria are used. For example, the bulk system is designed and operated so that if a fault occurs on a line, and a circuit breaker fails to operate correctly so as to clear the fault from the system, reliable service is maintained. This is sometimes referred to as an N-2 criteria.

Q. With the descriptions of reliability criteria, line outages, and transmission substation outages provided above as background, please describe some of the actual contingencies that are of concern in the LCSA, and the consequences of these contingencies.

A. To provide some insight into the dependency of the LCSA on key source or line outages, some specific examples are provided below starting with the most severe contingencies.

Loss of either the 3312 line from Middlesex or loss of the VELCO East Fairfax source:

1) At 35 to 40 MW - voltages less than 85%
2) At 48 MW - voltages as low as 78%
3) At 53 MW and above - voltage collapse likely

Loss of the 3313 line from Little River due to breaker opening:

1) At 69 MW - voltages less than 90%
2) At 72 MW - voltage collapse likely

Loss of the B22 line from the Morrisville No. 3 substation to Stowe:

1) At 80 MW - voltages less than 90%
2) At 81 MW - voltage collapse likely

Loss of the VELCO source at Irasburg:

1) At 67 MW - voltages less than 90%
2) At 85 MW - voltage collapse likely

Q. Does the data presented above convey additional information regarding the state of the existing system in terms of its reliability?

A. Yes. It shows that the system is very weak with regard to voltage stability. For example, referring above to the loss of the B22 line, a change of only 1 MW of load on the system makes the difference between an outcome of low voltage and one of voltage collapse. Systems with this level of weakness are difficult to operate with changing loads and are very susceptible to collapse and loss of load due to contingencies.

Q. In your opinion, have the petitioners considered and tested all reasonable transmission solutions?

A. Yes. I describe these alternatives in detail below.

Q. Do you agree that the models and analyses used by VELCO to test and develop the transmission solution were appropriate?

A. Yes. In the design of the proposed transmission upgrade, VELCO studied scenarios in detail using industry standard analysis and the best comprehensive system model available. This model includes detailed models of lines, transformers, generation, and projected loads. With regard to contingency simulation, VELCO appropriately simulated all likely first contingencies including line trips, open breakers, bus faults and transformer failures. Considering the detailed level of analysis performed, the review provided by other Vermont utilities, and my own review, I am confident that the analyses and models employed are appropriate and accurate.

Q. Please briefly describe the transmission solution that has been proposed by the petitioners.

A. The transmission solution proposed by the petitioners is comprised of: A) construction of a 115 kV circuit breaker on VELCO's 115 kV line from Middlesex to Essex; B) construction of a 115 kV switching site at Duxbury; C) construction of a new 115 kV single pole line from the Duxbury switching site on an existing GMP right-of-way via the Blush Hill tap to a new 115 kV/34.5 kV substation located next to the existing Stowe Electric Department Wilkens substation; D) reconstruction of the GMP single pole 34.5 kV line from the Blush Hill tap to the new substation; E) construction of a new substation located next to the existing Stowe Electric Department Wilkens substation comprised of a four-breaker ring bus and a 115 kV/34.5 kV transformer; and F) construction of a new 34.5 kV line from the new substation south to the existing 34.5 kV line to the Mount Mansfield area.

Q. Do you agree that the petitioners have proposed the appropriate transmission solution to the identified needs?

A. Yes. First, the proposed solution meets the needs, well into the future, for the "all lines in" condition. Second, the proposed solution provides reliable service, under first continency conditions, for load levels up to 98 MW.[6] As described below, alternative solutions provide reliable service for first contingencies, but for a shorter period of time into the future. And third, the proposed solution is the least cost among the alternatives.

Q. Can these upgrades be staged, or implemented in steps?

A. No. In order to provide the desired reliability, all elements of the proposed solution are required to be in service simultaneously.

Alternatives to the Proposed Project

Q. In your opinion, did VELCO consider all reasonable T&D alternatives to the proposed project?

A. Yes.

Q. Please briefly describe the transmission alternatives that were considered and analyzed by VELCO in its development of the proposed project.

A. VELCO analyzed more than 15 transmission alternatives. Among the most promising alternatives included: A) adding capacitors to the system to the maximum extent feasible; B) adding Flexible AC Transmission System (FACTS) devices to the system for dynamic voltage support; and C) adding a second 34.5 kV subtransmission line from Duxbury to Stowe.

[6]Assuming load growth as projected by the petitioners, the proposed solution would extend reliable service to the year 2021.

Q. With respect to the first alternative, would the installation of more capacitors on the local area system adequately address the problems identified?

A. No, the installation of capacitors alone would not work in this situation.

Q. Please explain.

A. Capacitors provide reactive power that supports and raises the voltage on a heavily loaded transmission network. For the area under consideration, in order to prevent voltage collapse under contingency conditions, the amount of reactive support would need to be increased very rapidly. Mechanically switched capacitors are not fast enough to do this. Fixed (unswitched) capacitors that are already on the system prior to the contingency, provide less and less reactive support as the voltage is reduced because the amount of reactive support is proportional to the square of the voltage. This phenomenon causes the voltage to plummet and possibly collapse. (See footnote 5 at page 4.) Also, the local area subtransmission system is a voltage constrained system. For such systems, sometimes referred to as "weak" systems, switching banks of capacitors can cause excessively large voltage variations. As a result, installation of conventional fixed or switched capacitors in this situation would be ineffective. What would be required, in the alternative, is a high-speed, continuously variable injection of reactive power into the network at key locations to maintain the voltage in the event of a contingency.

Q. Would installation of FACTS devices on the local area provide this high-speed, continuously variable injection of reactive power into the network?

A. Yes. FACTS devices are capable of providing high-speed, continuously variable injection of reactive power following contingencies. This would maintain post-contingency voltage.

Q. Why then do you not believe that installation of FACTS devices is an appropriate solution for this area?

A. Unfortunately, while FACTS devices address the *voltage* limitations, they do not address the *thermal* limitations of some of the circuits in the area. To address the thermal limitations, reconductoring existing 34.5 kV lines would be required. The cost of FACTS devices plus the cost of reconductoring results in this option being more costly than the proposed solution.

Q. Does construction of a 34.5kV subtransmission upgrade adequately address the problems identified?

A. Yes. However, as described in detail in the following section, this solution would maintain reliability to a lower load level than that achieved by the 115 kV option. Also, there is no significant cost advantage to a 34.5 kV solution due to the need for extensive reconductoring of existing 34.5 kV lines. In comparison, the 115 kV option, by virtue of its lower impedance, electrically strengthens the network and moves power more efficiently to the load center which in turn eliminates the need for expensive reconductoring.

Q. Members of the public have advocated for a solution that is comprised of a 115 kV line only, rather than the proposed 115 kV line and 34.5 kV located side-by-side between the Blush Hill Switch and the proposed VELCO Stowe substation. Do you agree that this would be an appropriate solution to the needs of the area?

A. No. While the 115 kV line would improve the “all lines in” performance of the system, faults on the 115 kV line would result in the same failure mode as that seen today with the loss of the 34.5 kV feed from Middlesex. In essence, the parallel 34.5 kV path retained by the proposal provides the necessary back up for the 115 kV contingency.

Q. Members of the public have advocated for a solution that removes the proposed 1.1 mile 34.5 kV tap line from the proposed VELCO Stowe substation to the existing Stowe Electric

Department 34.5 kV "mountain line." Instead, it has been suggested that the mountain line could be connected to the rebuilt 34.5 kV line that parallels the proposed 115 kV line, thereby eliminating the cost and aesthetic impact of the added 1.1 miles of 34.5 kV line. Do you agree that this suggested alternative would be an appropriate solution for the area?

A. No, this suggested alternative lacks important benefits provided by the proposed solution. First, the proposed solution provides the mountain line with a supply directly from the 34.5 kV ring bus at the proposed VELCO Stowe substation. This eliminates the loss of supply to the mountain line for faults on the 34.5 kV, 3313 line. Assuming a permanent fault outage rate of 0.12 per mile per year, supplying the mountain line directly from the new substation would eliminate approximately one extended outage per year for all customers connected to this line. Likewise, providing a separate feed from the proposed Stowe substation to the mountain line enhances reliability to the customers connected to the 3313 line, namely those customers served by the Waterbury Center substation. This is accomplished by eliminating exposure of the 3313 line to faults on the mountain line.

The 34.5 kV Transmission Option

Q. In your review of transmission alternatives, did you closely examine an alternative that you believed might provide a lower cost solution to the issues surrounding the LCSA.

A. Yes. Of all of the transmission options available, the so-called 34.5 kV option appeared attractive, at first glance, and deserved further scrutiny.

Q. Please describe the 34.5 kV option.

A. This option is comprised of a second 34.5 kV line, from Duxbury to Stowe, placed roughly in the same location as the proposed 115 kV line. A 115 kV to 34.5 kV transformer would be required and would be located at Duxbury rather than Stowe as in the proposed project. This 34.5 kV alternative appeared attractive, at first glance, in that construction of a 34.5 kV line would be less costly than constructing a 115 kV line. Also, I suspected that a 34.5

kV line would have less of an aesthetic impact than the proposed 115 kV line.

Q. Is the 34.5 kV option, in fact, less costly than the proposed 115 kV option?

A. No, for two reasons. First, this alternative would require reconductoring and reconstruction of some of the existing 34.5 kV subtransmission line in LCSA. According to VELCO's analysis, approximately 30 miles of the 34.5 kV lines in the LCSA would require reconductoring and reconstruction resulting in a capital cost that would be higher than that of the proposed 115 kV solution by approximately \$5 million.[7] And second, the line loss savings afforded by the 34.5 kV solution is approximately 0.8 MW less than that of the proposed 115 kV solution.

Q. Does the 34.5 kV solution provide the desired level of reliability to the same load levels as the proposed 115 kV solution?

A. No. The 34.5 kV solution would have a much shorter life than the 115 kV solution.

Q. Did you review the 34.5 kV option with an eye toward reducing its cost for the purpose of making it more competitive with the proposed 115 kV solution?

A. Yes. I reviewed the alternative as described by the petitioners and then developed what I believe would be a less costly 34.5 kV option. I reduced costs by using a double circuit, single pole construction north of Blush Hill tap and by including less reconductoring than the 30 miles proposed by VELCO. While such changes provide for somewhat less reliability than the VELCO 34.5 kV option, I believed that the resulting capital cost savings could conceivably make the reliability/cost tradeoff worth considering. Using VELCO's estimating methodology to allow for meaningful comparisons,[8] I arrive at an estimated cost of approximately \$20.3 million.

---

[7]This difference of \$5 million, identified in VELCO's response to DPS5-Petitioners-18, is revised from the \$10 million difference reported in VELCO's initial filing.

[8]See page 20 below for a discussion on VELCO's estimating methodology.

This compares to the VELCO estimate of $25.5 million for its version of the 34.5 kV option.

Q. What are your conclusions regarding a 34.5 kV transmission solution?

A. I believe that a 34.5 kV solution is not as attractive as the proposed 115 kV solution. First, the $20.3 million capital cost of my lower-cost 34.5 kV option is the same as the $20.3 million cost of the proposed 115 kV option. Second, the loss savings of my lower-cost 34.5 kV option is at least 0.8 MW less than that of the 115 kV proposal. And third, as stated above, a 34.5 kV option would have a substantially shorter useful life than the proposed 115 kV option.

Alternative Route for the Proposed 115 kV Line Along the Little River

Q. Members of the public have advocated routing the 115 kV line along the existing GMP 3312 and 3313 line corridors, in the general vicinity of the Little River, for the portion of the project located south of the Blush Hill tap. Do you agree that this would be an appropriate route for the 115 kV line?

A. No. First, this route would result in additional length to the 115 kV line. This additional length would add cost to the project and add exposure to possible contingencies. Second, the existing corridor through State Forest land would require more clearing of trees. Third, several crossings of the Little River would be required which would locate structures close to the river and in low-lying wet areas with potential environmental impact. Fourth, construction and maintenance of the line due to its proximity to the river would be difficult. And finally, in order to maintain the electrical connection to the existing Little River generating station, either a new substation would be required or the corridor in question would have to be widened even further to accommodate both the new 115 kV line and the existing 34.5kV line.

Alternatives for the Proposed 115 kV Line Configuration

Q. VELCO proposes the use of separate structures for the 115 kV and 34.5 kV lines north of the Blush Hill tap. Would the use of single pole structures supporting both lines be feasible?

A. Yes. I believe that a configuration comprised of single poles supporting both circuits would be feasible.

Q. What are the advantages of single pole double circuit construction for this application?

A. First, the number of poles required is reduced. This alters the appearance and, as discussed in the testimony of Department witness David Raphael, provides an aesthetic benefit. Second, this would allow the 34.5 kV circuit to be moved closer to the center of the right of way (ROW) decreasing the likelihood of tree contact on this circuit. And third, the shield wire would afford lightning protection for the 34.5 kV circuit. The cost of conventional single pole double circuit construction using embedded poles should be similar to that of the proposed double circuit construction using separate structures.

Q. What are the disadvantages?

A. The major disadvantage is that this mode of construction introduces an obvious common failure mode in that failure of a structure can cause an outage of both circuits. Second, should a tall danger tree fall, it has a higher likelihood of contacting both circuits. And third, for a given span length, pole heights would be on the order of 12 ft. to 15 ft. higher than those needed for the proposed construction.

Q. Please explain the difference in susceptibility to double circuit failures due to danger trees falling and faulting both circuits for both the single pole double circuit configuration that you propose and the separate pole configuration proposed by the petitioners.

A. First, I note that both modes of construction are susceptible to danger trees falling and taking out both circuits. The difference between the two lies in the fact that the petitioners' proposal uses separate poles with circuit center lines separated by 25 ft. Therefore, assuming a 100 ft. cleared ROW, a danger tree with a height of almost 50 ft., located on the 34.5 kV edge of the ROW could take out both circuits, while a danger tree on the 115 kV side with a height of almost 75 ft. would be required to take out both circuits. For the single pole double circuit option, danger trees with heights of almost 50 ft. on either side of the ROW could take out both circuits. Therefore, for those locations where the single pole option is employed, it would be important that taller danger trees on both sides of the right of way be cleared.

Q. Given the discussion above, do you have concerns about the reliability of a single pole double circuit configuration for this application?

A. As long as danger trees on both sides of the ROW can be removed, both at the time of construction and during the life of the line, this configuration should be reliable.

Q. Are there ways to alter the appearance or to reduce the heights of the 115 kV structures proposed by VELCO?

A. Yes. A number of alternatives are available that are variations on the single pole design proposed by VELCO. These alternatives include: 1) reducing the span length; 2) reducing the pole height above the topmost conductor attachment; 3) compressing the vertical distance between the conductors; 4) increasing the pole height; and 5) using Corten steel poles where pole color is important. Options 1), 2) and 3) reduce pole height while option 4) raises the height of the conductors so as to reduce the need to remove trees that provide visual screening or otherwise improve the appearance. Option 5) provides for a long term consistency of color where it is important to blend with the surrounding view.

Q. What pole height reduction can be achieved by Option 1) reducing the span length or length between the structures?

A. Where span lengths are relatively long, on the order of 430 ft., reducing the span to 300 ft., with no other changes can reduce the required pole height pole height by approximately 6 ft. due to a reduction in sag with shorter spans. It should be noted that a substantial portion of the proposed construction already uses spans on the order of 300 ft., so application of this option is limited. Also, there may be other factors governing placement of the poles that may rule out this option in some areas.

Q. Please describe what is involved with Option 2), reducing the pole height above the topmost conductor attachment, and the amount of pole height reduction afforded by this option.

A. The proposed design extends the pole approximately 12.35 ft. above the highest conductor, providing a lightning shield angle of approximately 60 degrees. For longer span lengths, this distance allows clearance for ice galloping effects. It also allows ample shielding for lightning protection purposes. In my opinion, this height above the top attachment could be reduced by 4.5 ft., thereby reducing the lightning shield angle to 45 degrees without degrading the lightning protection significantly below that of existing VELCO designs. It is also important to note that most lightning induced outages are momentary in nature, and as such do not pose a reliability threat unless coupled with another outage. In addition, where the span lengths are on the order of 300 ft., the ice galloping problem is mitigated by the reduced sag afforded by these shorter spans.

Q. Please describe what is involved with Option 3), compressing the vertical distance between the conductors, and the amount of pole height reduction afforded by this option.

A. The proposed vertical spacing between conductors on the side of the pole where two conductors are located is 15 ft. For single circuit structures, this provides a triangular configuration with the single conductor on the other side of the pole. If desired, where span lengths are on the order of 300 ft. or less, and davit arm structures are utilized, this vertical distance could be reduced slightly by perhaps 2 ft. This is limited by the proximity of the steel davit arm immediately below the top conductor. If braced post insulators are used, a greater reduction on the order of 7 ft. could be realized. The primary factor in this case is vertical motion of the conductor with regard to a sudden release of ice buildup and motion due to wind induced ice-galloping. As the span is reduced, the potential adverse impact of reducing the vertical distance diminishes. Therefore, height reductions of 2 ft. to 7 ft. are possible depending on the structure type.

Q. Can Options 1) through 3) all be applied to the same structures to achieve an additive reduction in pole height?

A. Yes, they can be combined to achieve a total reduction in pole height on the order of 12.5 ft. to 17.5 ft. depending on the structure type and where spans are reduced from 430 ft. to 300 ft. Where spans are already on the order of 300 ft., options 2) and 3) can be combined to achieve a reduction of 6.5 ft. to 11.5 ft. depending on structure type.

Q. Can the options be applied over short segments of the line?

A. Yes, they can be applied to a segment of line comprised of a few single pole structures.

Q. Can these options be applied to single pole double circuit configurations?

A. Yes. In the case of single pole double circuit configurations, three conductors instead of two are placed on one side of the pole. Therefore an additional reduction of 2 ft. for Davit arm construction and 7 ft. for post insulator construction, providing a total reduction of 4 ft. to 10 ft., can be gained due to compressing the vertical distance. This reduction applies to situations involving shorter spans and where the vertical spacing between conductors is 15 ft. This reduction can be added to that gained by the use of shorter spans and to that gained by reducing the pole height above the topmost conductor attachment.

Q. What do you recommend regarding alternative configurations for the proposed 115 kV line?

A. I recommend that VELCO utilize the above referenced options where aesthetic mitigation may be warranted. Department witness David Raphael discusses those sections along the corridor where such mitigation is required.

Project Cost

Q. What is your opinion of the petitioners' cost estimates for the proposed project?

A. First, I believe that all of the elements of the petitioners' proposal are necessary to achieve the reliability goals of the project and that inclusion of these elements reflect good utility practice. I see no evidence of "gold plating." Also, the construction labor and material (L&M) estimates provided for the proposed project appear to be reasonable. However, I believe that the estimates of adders to L&M may be somewhat overstated. Specifically, the petitioners' project additional costs that include: A) approximately 70% on L&M for VELCO engineering and outside consultants; B) approximately 35% on L&M for contingencies; C) 10% on L&M for construction interest; and D) Vermont tax on materials. This results in a total cost that is more than double the L&M estimate. For example, the L&M estimate for constructing the Stowe substation is approximately $2.64 million. The total project estimate including the adders described above is approximately $5.74 million. The respective values for the Duxbury switching site are $434,000 and $967,000.

Q. What is your estimate of the total project cost?

A. First, I note that the project estimate contains a "permitting cost" estimate of $1.5 million. I have no basis to challenge this number. Subtracting this from the petitioners' total project estimate of approximately $20.3 million yields $18.8 million. Of this total, approximately $10.2 million is for L&M. Based on my experience, and some consideration for market pressures, I think it would be more appropriate to assume a 50% adder to L&M for engineering, consulting, contingency, taxes and interest. This results in an estimated project cost, including the $1.5 million estimate for permitting, of $16.8 million, or roughly $3.5 million under the petitioners' estimate. Admittedly, market pressures are difficult to predict, so a higher actual cost could result.

Q. Are there other additions, beyond those included in the cost estimates provided by the petitioners, that are required to meet the reliability performance claimed by the petitioners?

A. Yes. The petitioners assume that capacitors will be added to the distribution systems in the LCSA, as required over time, to achieve a power factor of at least 98% throughout the forecast period. In addition, over the next 15 years, assuming load grows to approximately 98 MW, an additional 44 MVARs of capacitors will be required to be installed on the 34.5 kV system to maintain post contingency voltages of approximately 90% or above for loss of the 115 kV source.

Q. Do these requirements for additional capacitors effectively add cost to the proposed project?

A. No. Even in the circumstance that no other upgrades are made, as LCSA load levels increase, capacitor additions would be required to maintain voltage under the "all lines in" situation. The proposed configuration, with the added capacitors, provides reliable service under loss of all key elements, including loss of the proposed 115 kV source. Therefore, the capacitor additions should not be viewed as added cost to the proposed project.

Underground Considerations

Q. The topic of undergrounding portions of the proposed 115 kV transmission line has come up during the public hearings. What is the advantage of undergrounding.

A. The primary advantage of undergrounding is the lack of aesthetic impact since undergrounding takes the line completely out of view. However, depending on the type of cable system used, the structures required to transition the ends of the cable to the overhead line can be relatively unsightly when compared to single pole overhead structures.

Q. Please describe some of the disadvantages of undergrounding.

A. The major disadvantages of undergrounding include: 1) cost; 2) outage times required for repair and circuit restoration; 3) environmental impacts during construction; and 4) system design complications due to the electrical characteristics of underground cable.

Q. What are the cost implications of underground vs. overhead 115 kV circuits?

A. To get a rough idea of cost impact, the installed cost of cable can run on the order $4 to $6 million or more per mile for a single three phase circuit depending on many factors including terrain, cable configuration and market pressures. If directional drilling[9] is used, significant additional costs can be incurred. The cost of an overhead 115 kV line is on the order of $250,000 to $300,000 per mile. Therefore, the incremental cost of undergrounding is likely to be upward of $3.7 to $5.7 million per mile for one circuit.

Q. In the testimony of Department witness David Raphael, undergrounding at the Waterbury Reservoir is discussed. What would be the cost for undergrounding at this location?

A. In preparing a cost estimate, I made the following assumptions: First, I assume that directional drilling would be used to place the cable under the reservoir so as to minimize environmental impact. Second, I assume that the overhead to underground transition structures would be placed 700 ft. back from the south shoreline and 500 ft. back from the north shoreline to keep the transition structures out of view. Of this total of 1200 ft., 1100 ft. would utilize conventional trenching methods. The remaining 100 ft. involves extending the directionally drilled portion some 50 ft. from each shoreline. Third, I assume that both 115 kV and 34.5 kV circuits would be placed underground and that each circuit would utilize four XLPE cables to minimize outage time should a cable failure occur.

I also assume one directional boring under the reservoir and the placement of both cable systems into that bore. I believe that this configuration, as opposed to a configuration using two bores, should be reliable in that the chance of one cable failure inducing failure of another cable within the bore is very remote. This is due to the fact that the cables are sized to avoid any chance of excessive heating due to overloading. In addition, thermal stresses during faults would be minimized by using high speed relaying which opens the faulted circuit in fractions of a

[9] Directional drilling is a construction method used to place the cable under roads or to minimize environmental disturbance involved with crossing bodies of water, wetlands or other sensitive areas.

second. For the dry land portions, I assume that the circuits will occupy duct banks placed in separate trenches to avoid the common failure mode of an inadvertent excavation incident. Given the above assumptions, I estimate the cost of undergrounding both the 115 kV and 34.5 kV circuits at the Waterbury Reservoir to be in the range of $4.1 to $5.9 million.

Q. What are the comparative outage and circuit restoration times for overhead and underground configurations?

A. For overhead circuits, the response to two types of faults needs consideration. If a fault is temporary, such as caused by a lightning flashover, the circuit is tripped then reclosed (restored) seconds later by an automatic reclosing process. If the fault is permanent, the reclosure reestablishes the fault and the circuit trips a second time and remains open until the problem is located and repaired. Restoration can be achieved in several hours depending on the problem and the nature of the required repair. Roughly 2/3 of the faults at 115 kV are of a momentary nature with successful automatic restoration of the circuit.

For cable circuits, the scenario is different. Cable faults are almost always permanent and due to failure of the cable dielectric insulation. The fault location process is complicated and can take from several hours to several days before restoration of the healthy portions of the circuit can be achieved. If the fault is in the cable, total end-to-end restoration of the circuit can take on the order of two weeks or more to achieve. Addition of a fourth or spare cable during installation can reduce restoration time to a few days or less. If used for the LCSA, I would recommend a four-cable system to minimize exposure to second contingencies that could cause widespread loss of load. Given the relatively low outage rates of cable systems, coupled with an exposure time of a few days or less, when viewed from a probabilistic perspective, the use of undergrounding does not appear to pose a major reliability concern.

Q. What are the construction impacts and right of way maintenance requirements for undergrounding?

A. Environmental concerns relate to the severe disturbance created by excavation along every foot of the cable path vs. excavation only at pole locations for the overhead system. A 12 ft. to 20 ft. path along one side of the cable would be impacted. As discussed above, an alternative construction method to avoid impact at the surface is directional drilling. However, directional drilling adds even more cost to the project. Once a cable is installed, except for the directionally drilled portions, a right of way on the order of 50 ft. needs to be retained and maintained to facilitate repairs.

Q. What are the design complications regarding use of underground cable?

A. Underground cable has a much lower impedance than overhead lines. When used in a network with overhead lines, this impedance affects the distribution of power flowing in the circuits. Impedance mismatch at transition points causes unique transient phenomena when circuits are switched on and off. The cables have a relatively high value of shunt capacitance which can cause voltage issues for longer length applications. None of the above issues are "deal breakers" and therefore can be overcome by one means or another. My main point here is that application of cable as part of a system with overhead transmission requires careful modeling and study to ensure that there are no adverse impacts.

Reliability and Stability

Q. Does the proposed project adversely impact the reliability of the VELCO bulk power system?

A. Due to adding a relatively low impedance transmission path from VELCO's K24 line to the center of the LCSA subtransmission system, there will be a slight increase in momentary voltage dips on the bulk system due to faults on the subtransmission network. The impact will be mitigated by the impedance of the 115 kV to 34.5 kV transformer at Stowe and by the addition of modern high speed fault clearing relays and breakers at the proposed Stowe site. The added 115 kV tap from Duxbury north to Stowe provides increased exposure to faults on this section of line. This slightly increases the frequency of momentary voltage dips on the bulk system.

Outages of the K24 path to Essex, due to permanent faults on the 115 kV extension north from Duxbury, will only last for seconds due to the addition of high speed automatic sectionalizing equipment to be added at the Duxbury switching station. (This feature has been added since the filing of VELCO's direct testimony.)

On the other hand, addition of the 115 kV breaker at Middlesex expedites the determination of fault location on the line section between Barre and Essex thereby enabling more prompt repair and restoration of this important transmission path. Overall, the reliability improvement afforded by the K24 breaker addition outweighs the slight increase in the addition of momentary voltage dips.

Q. Please describe the reliability and stability impacts of the proposed project on the local area subtransmission system.

A. The addition of the proposed 115 kV source near the electrical center of the LCSA substantially strengthens the network. The result is that momentary voltage dips are substantially reduced in magnitude. As described above, the addition of modern relays and breakers at the proposed new substation will decrease the duration of these voltage dips.

Also, as described above, the project as proposed will provide reliable N-1 performance for all likely contingencies up to a load level of 98 MW.

Operational Impacts

Q. What are the potential operational impacts of the proposed project for the VELCO bulk transmission system?

A. As described above, the addition of a new 115 kV breaker at the VELCO Middlesex substation will reduce restoration time of the 115 kV path from Barre to Essex for permanent faults.

Q. What are the potential operational impacts of the proposed project for the local subtransmission system?

A. The addition of the 115 kV source substantially strengthens the LCSA subtransmission network. This provides greater voltage stability under changing load conditions and contingency situations. This greatly reduces the need for operator vigilance and reduces the need to maintain voltage by manually switching capacitor banks in and out. The reduced likelihood of having to restore the system after widespread outages occur has obvious advantages. An additional benefit of the stronger LCSA system is enhanced stability of generation sources connected to the system. These sources would be less likely to trip off line for faults on the system.

Safety

Q. Do you believe that the proposed transmission lines would be safe?

A. Yes I do, for the following reasons: First, the proposed transmission lines would be constructed consistent with the National Electric Safety Code (NESC). I note that compliance with the NESC meets the construction safety standards for Vermont electric systems established by the Public Service Board in its Rule 3.500. Second, new infrastructure would replace older existing structures. This new infrastructure should make the proposed line less susceptible to failure. Third, I note that VELCO employs a four-year tree trimming cycle for its transmission system. This tree trimming cycle is the most aggressive cycle used by any Vermont electric utility and would minimize the occurrence of damage to the lines from adjacent trees. Fourth, VELCO patrols its transmission lines on a regular basis. The patrols include infrared surveillance of the lines which detect “hot spots” which are an indication of incipient failure of mechanical connections. As such, VELCO would be able to promptly identify and repair any deficiencies it found in order to limit the occurrence of component failures. Fifth, VELCO is pursuing upgrading the existing ROW maintenance agreements to include the right to remove danger trees outside of the ROW thereby reducing the chance of a tree falling on the line and creating failure and /or electrical hazard. Finally, VELCO would monitor its lines automatically with state-of-the-art relays and protection systems. These systems have built in redundancy and, if needed, switch off the power to a fallen line in fractions of a second.

Audible Noise Impacts

Q. What are the potential noise impacts of the proposed project?

A. The only potential for noise increase is from the new transformer that would be located at the proposed VELCO Stowe substation.

Q. Is VELCO addressing the potential audible noise impacts?

A. Yes. VELCO, through its consultant Resource Systems Group (RSG), has taken baseline noise measurements at the proposed substation site, modeled the proposed substation, and provided estimates of worst case noise levels at existing or planned home sites in the area. As a result, RSG concludes that noise levels due to the additions at the proposed site will not have an undue adverse impact on the area provided that the 115 kV to 34.5 kV transformer to be installed generates noise 8 to 9 db below NEMA TR-1 specifications.

Q. What recommendations do you have for the Board with respect to potential noise impacts?

A. The Board should require post-construction noise measurements at the existing and planned home sites to ensure that the "as constructed" operating noise is equal to or lower than the estimated levels arrived at through computer modeling. Further, the Board should retain jurisdiction to require VELCO to take all reasonable steps to address noise concerns identified by the public, as a result of the project.[10]

Losses and Efficiency

Q. What effect will the NRP have on the overall operating efficiency of the transmission system in terms of losses?

A. For the area under consideration, assuming a peak load of 77 MW, the proposed

[10] For example, "tonal noise" or noise within a coherent frequency band, could become evident post construction. This type of noise can propagate in unusual ways and be particularly irritating, even when below threshold decibel levels.

project would reduce system electrical losses, at peak, by approximately 3.7 MW. Additional loss savings of 0.4 MW would be obtained outside of the local area. Total loss savings will increase significantly with additional load growth. These loss savings are significant, and from a societal perspective, substantially reduce the overall cost of the project.

Q. Does this conclude your testimony?

A. Yes.